# TECHNICAL REVIEW DOCUMENT for OPERATING PERMIT 950PPB025

to be issued to:

WestPlains Energy (Division of UtiliCorp United)

Pueblo Power Plant

Pueblo County

Source ID 1010008

Michael E. Jensen March 6, 1997

#### I. PURPOSE:

This document will establish the basis for decisions made regarding the applicable requirements, emissions factors, monitoring plan and compliance status of emission units covered by the operating permit proposed for this site. It is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the original application submittal of January 27, 1995; a supplemental technical submittals of August 7 and October 16, 1996; a site visit on September 17, 1996; previous inspection reports as well as numerous telephone conversations with the applicant.

### II. SOURCE DESCRIPTION:

This facility is located in Pueblo, Colorado. Pueblo is classified as an attainment area for all criteria pollutants. There are no affected states within 50 miles of the facility. The Great Sand Dunes National Monument is a designated Federal Class I area within 100 kilometers of the facility. Florissant Fossil Beds is a Federal land area within 100 kilometers of the facility. Florissant Fossil Beds has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

There have been several steam driven generating units at the facility since the early 1920s. Unit #1922 (boiler #1, #2 and #3, and turbine #4) was converted from coal burning in the 1960s. The unit was permanently removed from service about January 1, 1990. Unit #1941 (boiler #4 and turbine #5) was permanently removed from service on December 14, 1994. All the equipment for Units #1922 and #1941 are reported to be permanently disabled and no longer usable. The old cooling tower system has been demolished.

The current primary features of the facility are one steam driven electrical generating unit and five (5) identical diesel engine driven electrical generating units. The steam boiler has a rated capacity of 185,000 pounds per hour. The turbine/generator unit has a nominal capacity of 15 megawatts and nameplate rated capacity of 16.5 megawatts gross turbine output. The current operating unit, known as Unit #1949, was placed in service in 1949 as a pulverized

coal burning boiler, using natural gas or fuel oil as alternate fuels. In 1991, the unit was permanently converted to use natural gas and fuel oil only.

The diesel engine driven generators were placed in service in 1964. Each unit is identical and rated at a nominal 2000 kilowatts. The diesel units may be used to respond to peak demands, or for generation of electricity if the steam unit production must be reduced or the boiler taken out of service. The diesel engines are on a routine exercise schedule of approximately three (3) hours of operation per month to ensure the equipment will function when needed.

The combined nominal capacity ratings for the steam driven generator (15 MW) and the five diesel generators (10 MW) is 25 MW. However, normal plant production is about 10 MW from the boiler unit only.

The steam boiler and the diesel generators all had construction permit and New Source Performance Standard grandfather status at the time of the submittal of the operating permit application. Therefore, no construction permits were replaced by this operating permit. None of the units are subject to Title IV.

The 325,000 gallon and 250,000 gallon above ground storage tanks (AST) for fuel oil storage have been replaced with one 300,000 gallon AST. This tank required a construction permit to recognize the requirements of the New Source Performance Standards.

The Potential-to-Emit values in the following tabulation of emissions was extracted from the Title V application. The actual emissions are from the Division Aerometric Information Retrieval System (AIRS) database for the 1994 data year. An inspection of the table finds the actual emissions are a fairly consistent percentage of the boiler natural gas potential-to-emit values. This would indicate little contribution to the actual emissions from the operation of the diesel units.

POLLUTANT	POTENTIAL TO EMIT, TPY				FACILITY
	BOILER		1 DIESEL	5 DIESEL	ACTUAL EMISSIONS,
	NG	#2 FO	GENERATOR	GENERATORS	TPY
PM	3.57	14.77	22.60	112.98	1.60
PM <sub>10</sub>	3.57	7.39	21.59	107.93	1.59
$SO_X$	0.71	1060.63	21.05	105.23	0.46
$NO_X$	654.78	177.26	316.35	1581.75	260.66
VOC	1.67	1.48	21.65	108.26	0.84
СО	47.62	36.93	68.80	344.01	19.20
HAPS					0.11*

NG = natural gas #2 FO = #2 Distillate

The Title V application reports this facility is not subject to the requirements of Section 112(r)(7), the Accidental Release Plan program of the Clean Air Act. File information and the Title V application indicates the boiler and the engines are not subject to the requirements of Title IV, the Acid Rain Program of the Clean Air Act.

The compliance status of each source is based on the information provided in the application and a review of the office files available. No non-compliance issues were discovered in the file review. The Division accepts the facility was in compliance at the time the Title V application was submitted. Since no compliance plan or schedule was included for start-up, shut-down or malfunction opacity exceedances, it is accepted that the facility has adequate and appropriate control programs in place.

## III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

# Units B001 - 246 MMBtu/Hr Babcock and Wilcox Boiler

**1. Applicable Requirements** - B001 went into service in 1949 and qualifies for the grandfather exemption from the need for a construction permit. The unit is subject to the requirements of State Regulation #1 which uses the following equation to establish a particulate emissions limit:

<sup>\*</sup> Does not include combustion HAPs

 $PE = 0.5(FI)^{-0.26}$  PE = Particulate Emissions in pounds per million Btu heat input <math>FI = Fuel Input in Million Btu (MMBtu) per hour (Hr)

The limit set by this equation for each of these boilers is 0.120 pounds of particulate per MMBtu. A calculation using the AP-42 emission factor (5 pounds per million standard cubic feet) and the natural gas heat content (850 Btu per standard cubic foot) results in a value of 0.0059 pounds per million Btu, which demonstrates the standard will not be exceeded when burning pipeline quality natural gas. A similar calculation can be made for the distillate fuel oil. Using the AP-42 emission factor (2 pounds per thousand gallons) and the distillate heat content (136,916 Btu per gallon) results in a value of 0.0146 pound per million Btu which again demonstrates the standard will not be exceeded when commercially marketed distillate is burned.

B001 is subject to the standard set by Regulation No. 1, §VI.A.3.b.(i) when burning fuel oil. The standard is set at 1.5 pounds of sulfur dioxide emissions per million Btu of heat input. A calculation using the stored fuel oil heat value and sulfur content reported in the Title V application, combined with the AP-42 emission factor for SO<sub>2</sub> identifies the facility to be in compliance with the SO<sub>2</sub> emission standard. The sulfur content of the stored fuel oil is given as 0.31% by weight and would have to exceed 1.45% by weight (at the current heat content level) to exceed the standard. Because the standard is related to the heat and sulfur content and not fuel consumption, the facility will be required to demonstrate compliance with the standard on each occasion that both fuel oil is burned and the sulfur/heat content of the fuel has changed since the last firing. This reduces the monitoring requirement to an analysis of the heat content and per cent sulfur of the stored fuel oil after each addition of fuel oil to the storage tank. A change in these values requires the calculation of compliance using the new values the next time fuel oil is fired.

**2. Emission Factors** - Emissions from the boiler can result from burning natural gas and No. 2 distillate. The primary criteria pollutants of concern are nitrogen oxides (NOx) and sulfur oxides (SOx). Standard factors from the AP-42 manual were selected for estimating the actual emissions. The sulfur dioxide emission factor incorporates the fuel oil sulfur content. In addition, the fuel oil heat and sulfur content are needed to determine compliance with the Regulation #1 sulfur dioxide limit. The Title V application reported the sulfur content as 0.31% and the heat content as 136,915 Btu per gallon for the stored fuel oil. Since the heat and sulfur values can span a range of values, a fuel analysis is necessary to establish the actual values.

The facility has the capability to burn fuel oil and natural gas simultaneously. There are no readily available published emission factors for this scenario. However, based on engineering judgement, the emissions should be representative of each fuel fraction. As such, total emissions under this scenario will be estimated as the sum of emissions from the

fuel oil fraction and natural gas fraction.

A new 300,000 gallon above ground storage tank for the No. 2 distillate was placed in service around the start of 1996. This tank replaced a 250,000 gallon and a 300,000 gallon tank previously used. The tank provides fuel oil storage for both the boiler and the diesel generators. The estimated annual fuel oil usage is in the range of 10,000 to 20,000 gallons per year. At the current estimated use rate, it would require 15 to 20 years to replace the contents of the tank. West Plains reports currently purchasing "low sulfur" fuel oil. The sulfur content of the fuel oil currently stored in the new tank has not been reported. The continuation of the purchase of "low sulfur" fuel oil should limit the fluctuation of the sulfur content to a short range of values. The combination of the continued purchase of "low sulfur" fuel and the limited fuel oil usage allow a once a year sampling of the tank contents to be adequate to monitor any changes in the fuel quality.

The application sampling protocol proposal for the collection of a single grab sample from the tank is considered to be too limited to represent the entire tank contents. The sampling plan will need to be modified to provide a composite sample created from equal amounts of a grab sample collected from the upper one-third and the lower one-third of the tank.

**3. Monitoring Plan** - The grandfathered status of the boiler reduces the amount of monitoring required. Since the unit operates as the primary power supply it is expected that there would be limited startups. Startups for large boilers may take an extended time and may result in significant opacity. Operating staff experience may have an affect on the both the startup time required and opacity levels.

The general operating procedure for the boiler is to use natural gas for boiler startup. The pilot lights for the boiler burners are natural gas fired. The burners can not be ignited without the pilot lights. When the boiler is placed in service from a cold standby, the unit is heated by burning natural gas. It takes approximately 12 hours to bring the boiler up to the steaming level necessary to operate the turbine, synchronize the generator, and supply electrical power. No cold starts are made with fuel oil. Once the turbine is in operation, the natural gas supply can be replaced by fuel oil if necessary. If the boiler switches to burning the fuel oil, the switch-over is accomplished burner-by-burner until the desired number of burners are using the fuel oil. The process is reversed to return to natural gas service. The boiler can be placed in service in an emergency mode in as little as two hours. However, the stress on the components is quite severe and lead to substantial damage. Emergency startups are avoided in so far as possible.

When natural gas delivery must be interrupted or is curtailed by the vendor, a number of options are available to the plant manager. The options include: continue operating the boiler on the amount of natural gas available, and either purchase the supplemental electrical power needed, or operate the standby generators; operate the boiler at full production by switching

partially or completely to fuel oil; or combinations of the various options.

The Division accepts the position that, based on AP-42 emission factors and engineering judgement, the combustion of natural gas in a properly operated facility does not produce enough particulate matter to require opacity observations. Fuel oil use, however, has a significant potential for opacity problems, particularly for cold startups. The startup and shutdown procedure practiced at this facility minimizes the potential for opacity problems. The opacity monitoring prescribed by the permit is intended to validate that the fuel switch-over does not create a problem.

The need for monitoring of the sulfur content of the fuel oil was described above in relationship to the emissions factor application. The heat content of the fuels is also needed for determining compliance with the Regulation 1 limits. The sulfur dioxide emissions from burning pipeline delivered natural gas are only a fraction of the Regulation 1 emission standard. It is unlikely the standard would ever be exceeded while burning natural gas. On this basis the monitoring interval was set at an annual interval.

For emissions of less than 100 TPY of a criteria pollutant, an increase in actual emissions of 5 TPY or more, above the value reported on the last APEN submitted requires a revised APEN to be submitted. For emissions of 100 TPY or more of a criteria pollutant, an increase in actual emissions of 5 percent or 50 TPY or more, above the value reported on the last APEN submitted requires a revised APEN to be submitted. The estimated actual annual emissions for NOx exceed 100 TPY, therefore a revised APEN is required for a 5% or 50 TPY or more increase in any criteria pollutant.

**4.** Compliance Status - The Title V application reported a Method 9 observation was performed by a State certified observer while burning natural gas and while burning No. 2 fuel oil on December 9, 1994. The opacity was reported to be 4-5%. The Division accepts the unit was in compliance at the time the Title V application was submitted.

# Unit E01, E02, E03, E04, E05 2000 KW Diesel Driven Generators

- 1. Applicable Requirements The generator units were place in service in 1964. Each generator has a nominal rating of 2000 Kilowatts. Each diesel engine is equipped with a turbo charger and has a calculated horsepower rating of 2,682. The diesel generators have regulatory grandfather status and do not require construction permits. The Division interpretation of the Regulation #1 definition of fuel burning equipment excludes internal combustion engines. Therefore, only the opacity limits are applicable requirements.
- **2. Emission Factors** The emission factors are taken from EPA FIRE Version 5.0. The sulfur dioxide emissions do not require any adjustment for the sulfur content on the diesel fuel.
- **3. Monitoring Plan** The engines have been in existence for over 30 years. The amount of wear on the engine parts, the level of maintenance, altitude, and a number of other similar factors all have an impact on the engine emissions. Rocky Ford, Colorado, test results on engines that are identical models to the Pueblo engines identified NOX and CO emission factors significantly different from the AP-42 values. The applicant stack test emission factors for the Rocky Ford engines were used instead of the AP-42 factors. The monitoring program set forth is intended to establish the actual emissions levels and a performance record for each engine.
- **4. Compliance Status** The Title V application reported a Method 9 observation was performed by a State certified observer for all the units on December 9, 1994. The opacity was reported to be 4-5%. The Division accepts the units were in compliance at the time of the preparation of the application.

**Alternate Operating Scenarios** 

No alternate operating scenarios were identified

## **Fuel Oil Storage Tank**

- **1. Applicable Requirements** The tank is subject to the record keeping requirements of 40 CFR Part 60, New Source Performance Standards, Subpart Kb §60.116b. Construction Permit 96PB895 also set annual VOC emission limits and an annual throughput limit for the tank.
- **2. Emission Factors** The emissions from No. 2 distillate are low. The emissions were calculated by EPA's TANKS 2 software.
- **3. Monitoring Plan** The monitoring plan requires the dimensions and capacity analysis of the tank to be kept for the life of the tank. Records of the annual throughput of No. 2 distillate must also be kept on file.
- **4.** Compliance Status The storage tank was constructed and placed in service about January 1996, approximately a year after the Title V application was submitted. An APEN and a construction permit should have been submitted in advance of the construction of the tank. This was not done. The discovery of the oversight was corrected by requesting the missing documents and issuing the necessary permit.

## **Permit Shield**

No permit shield was requested.

## **Hazardous Air Pollutants**

At the time the Title V application was submitted, the reporting of estimated actual hazardous air pollutants (HAPs) emissions from combustion at utility steam boilers used for electrical power generation had been deferred until the findings of an EPA scientific study were released, or September 30, 1996, whichever came earliest. In an effort to provide an estimate of the potential-to-emit for the combustion HAPs, the Title V application used emission factors available from AP-42 for calculation of the best available approximation of the emissions. The permittee has reported the estimated HAPs to the Division in accordance with the September 30, 1996, deadline. The review of the information submitted

has not yet been completed; therefore, the information is not yet available from the Division database.

The limited use of fuel oil results in an insignificant contribution to the HAPs levels. The HAPs currently reported in the Division database are from the miscellaneous use of paints, thinners, solvents and the existence of the gasoline under-ground storage tank at the time of the last emission report. The under-ground storage tank has been removed since the entry of this HAPs information in the Division data base.

## **Miscellaneous**

A number of the forms were not provided with the application. The information that would have been provided by the missing forms was available on other forms, or elsewhere in the application. The judgement was made that no beneficial purpose would result from requiring the submission of the missing forms.

From time to time published emission factors are changed based on new or improved data. A logical concern is what happens if the use of the new emission factor in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors or emission factor equations included in the permit are considered to be fixed until changed by the permit. Obvious factors dependent on the fuel sulfur content or heat content can not be fixed and will vary with the test results. The formula for determining the emission factors is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, and to notify the Division in writing of impacts on the permit requirements when there is a change in factors. Upon notification, the Division will work with the permittee to address the situation.